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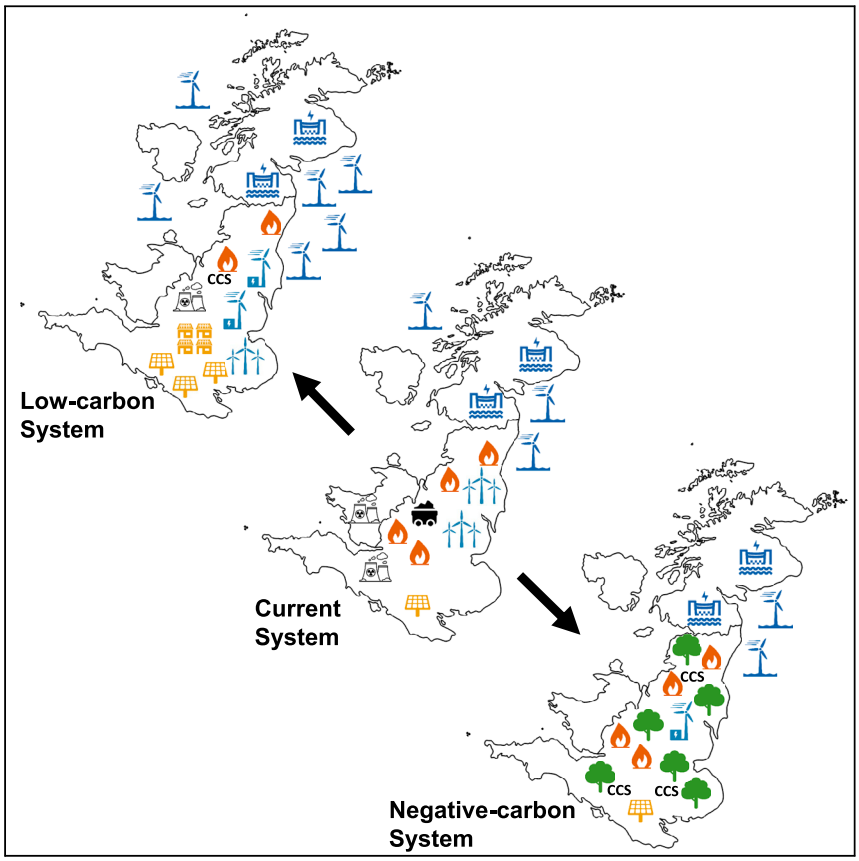
Structural Evolution of the UK Electricity System in a below 2°C World



The UK wants to reduce GHG emissions commensurate with the Paris Agreement. Thus far, this has led to the rapid uptake of renewable energy technologies. We find that while renewables are sufficient to deliver a low-carbon system, they cannot deliver the large-scale atmospheric carbon dioxide removal required to meet the Paris targets. We find that this is best achieved through a system dominated by thermal generation, particularly from gas and bioenergy power plants, both with CCS.

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HIGHLIGHTS

A renewables-dominated system cannot deliver zero-carbon power cost-effectively

CCS and CDR deployment are critical to delivering the Paris Agreement

Decentralization of energy services may hinder deep decarbonization efforts

Incentives must be provided for CDR to achieve deployment at necessary scale

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Structural Evolution of the UK Electricity System in a below 2°C World

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SUMMARY

We employ an electricity system model to determine the least-cost transition necessary to meet a given carbon dioxide removal (CDR) burden in the UK. The results show that, while sufficient in the medium term, a system dominated by intermittent renewable energy technologies (IRES) cannot deliver CDR at the scale required in a cost-effective manner. The marginal value of IRES for climate change mitigation diminishes with time, especially in the context of the Paris Agreement. Deeper decarbonization precipitates a resurgence of thermal generation from bioenergy and gas (with carbon capture and storage) and nuclear. Such a system is inherently centralized and will require maintenance of existing transmission and distribution infrastructure. Current policy direction, however, encourages the proliferation of renewables and decentralization of energy services. To avoid locking the power system into a future where it cannot meet climate change mitigation ambitions, policy must recognize and adequately incentivize the new technologies (CCS) and services (CDR) necessary.

INTRODUCTION

Climate change has become a mainstay of global political discourse since the 2015 Paris Agreement. Through the accord, all nations committed to keeping the increase in global average temperature to "well below 2°C above pre-industrial levels" by 2100 and pursuing further efforts to restrict it to 1.5°C. Integrated assessment models (IAMs)—climate-economy models that inform on the socioeconomic consequences of greenhouse gas (GHG) emissions—have estimated that cumulative anthropogenic GHG emissions (also known as the "carbon budget") must be limited to 590–1,240 Gt_{CO_2-eq} between 2015 and 2100 to deliver the Paris accord (>66% probability).[1] The mitigation actions (reducing the sources or enhancing the sinks of GHGs) pledged by countries in their nationally determined contributions (NDCs), however, are insufficient to achieve this; even if NDCs are successfully implemented, the available carbon budget will be exhausted between 2045 and 2075.[2] Large-scale carbon dioxide removal (CDR) from the atmosphere is therefore critical to compensate for an exceedance of the 2°C carbon budget.[3] IAMs show that a cumulative 430–740 Gt_{CO_2} of CDR is necessary by the end of the century, beginning as early as 2020 and reaching 10–20 Gt_{CO_2}/year in 2100.[3,4] This is largely achieved through land-based CDR,[5] in the form of afforestation and reforestation (AR) and using bioenergy with carbon capture and storage (BECCS).

Although other forms of land- and ocean-based CDR techniques are extensively discussed in the literature, they remain largely theoretical.[6,7] Direct air capture and storage (DACS)—the direct removal of CO_2 from the atmosphere using a range of

Context & Scale

The 2008 Climate Change Act mandated the reduction of UK economy-wide greenhouse gas emissions by 80% (relative to 1990 levels) by 2050. Policies and legislation encouraging the proliferation of low-carbon energy sources and improved energy efficiency and disincentivizing fossil fuel use have been successfully implemented to this end. The Paris Agreement, to which the UK is committed, however, requires deeper decarbonization to be achieved, including the global deployment of gigatonne-scale carbon dioxide removal (CDR). To align its decarbonization efforts with the Paris Agreement's long-term ambitions, the UK seeks to strengthen its emission reduction targets and transition to a net-zero carbon economy. This study assesses the possible implications of such an ambition on the UK's incipient energy transition and, more broadly, the consequences of CDR deployment on long-term electricity system transitions.

sorbents—has emerged as another technological option for CDR, with several demonstration projects seeking to establish its commercial viability.[8] Studies that assess the CDR potential of BECCS and DACS technologies have been carried out in the context of isolation[9]; therefore, they fail to quantify their relative values within the broader energy system.

The majority of the cumulative CDR needed to satisfy the 2°C carbon budget by 2100 is provided by BECCS in six regions[10]: China (20–170 Gt_{CO_2}), the United States (10–140 Gt_{CO_2}), India (0–90 Gt_{CO_2}), the European Union (EU; 20–70 Gt_{CO_2}), Brazil (20–150 Gt_{CO_2}), and Russia (10–80 Gt_{CO_2}).[4,11,12] Because of the formulation of IAMs, the EU's CDR requirements are not further geographically disaggregated. How and where this CDR burden should be achieved, at a national level where climate policy is implemented, is therefore unknown, and the implications of these quotas on country-level energy system transformations are largely absent.

This study seeks to fill these gaps by (1) quantifying the CDR requirements for the UK according to established fairness principles and (2) determining the electricity system transition necessary to meet those requirements, since scenarios obtained from the IAMs attribute most, if not all, of CDR in the energy system to BECCS in the power sector.[4]

Burden Sharing to Deliver the Paris Agreement

It has been established that the countries with the greatest responsibility for climate change and the capacity to address it differ greatly from those most vulnerable to its adverse impacts.[13,14] Consequently, international climate policy has emphasized the need for fairness in establishing the relative burden of action to be taken by governments to stabilize GHG concentrations at non-dangerous levels.[14] The United Nations Framework Convention on the Climate Change Treaty states that member parties should protect the climate system "on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities."[16] However, there is no objective definition of how fairness should be assessed within the context of international climate policy.[15,17] Several sharing principles have been proposed to equitably distribute the economic burden of climate change mitigation. Some of these principles and their implications for the UK's climate-change mitigation burden have been illustrated in Figure 1 and are detailed in Table S1.

These burden-sharing principles seek to establish a politically optimal distribution of responsibility for climate change mitigation. However, in reality, CDR is more feasible in some countries than others because of bio-geophysical and socio-political factors, e.g., an abundance of bioenergy resources, availability of low-carbon energy, or geological sinks for CO_2. Consequently, a cost-optimal distribution of the CDR burden may require cooperation between nations. This is not taken into account in this study. Despite the weaknesses of the interpretations of distributive fairness,[21–23] the principles have been used to ascribe regional carbon quotas and determine the sufficiency of existing climate change mitigation commitments to achieve them.[15,23]

For the purpose of this study, we assume that the EU's CDR burden is allocated to member states in proportion to their responsibility for the climate change problem, i.e., based on their cumulative historic emissions. The UK is responsible for 14% of the EU's historic emissions (see Table S1); this corresponds to a cumulative CDR requirement of 2.8 to 9.8 Gt_{CO_2} by 2100. We subsequently analyze the implications of this scale of CDR on the UK's electricity systems transition.

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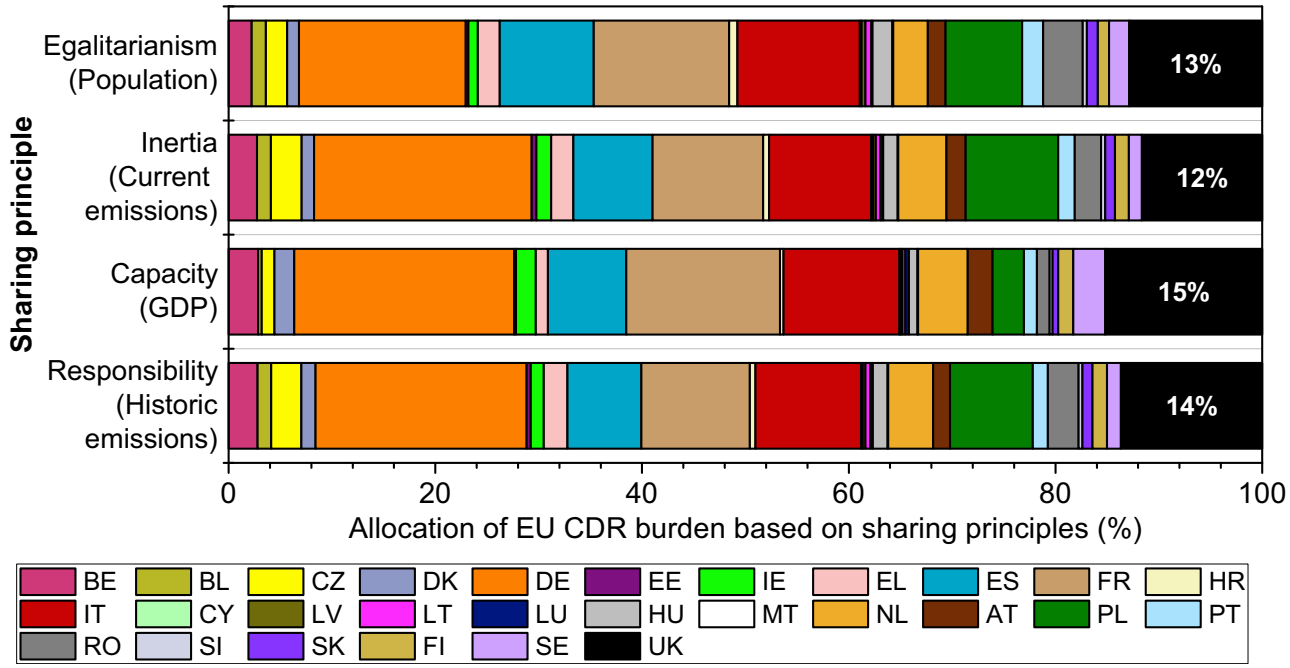

Figure 1. Allocation of the European Union's CDR Burden According to Proposed "Fairness Principles"
Population and GDP data are obtained from Eurostat[18,19]; member states' historic greenhouse gas emissions are obtained from the European Environment Agency.[20]

Modeling Framework

The national electricity system was modeled using the Electricity Systems Optimisation with capacity eXpansion and Endogenous technology Learning (ESO-XEL) in this study.[24] ESO-XEL is a mixed integer linear optimization model that determines the least-cost evolution of a power system in five-yearly time steps, subject to a range of constraints: hourly demand is satisfied; grid reliability and operability are constantly maintained; until 2050, the maximum carbon emissions allowance for the system is restricted to the five-yearly power-sector carbon budgets advised by the Committee on Climate Change (CCC)[25]; and maximum build and ramping rates are specified per technology. Technology-specific cost learning is also implemented endogenously in the model, i.e., capital costs are assumed to vary with additional capacity deployment, not with time. Although ESO-XEL treats the entire system as a single node, losses resulting from power transmission and distribution are accounted for. The mathematical formulation of the model has been defined previously[24] and is available as an open-access and open-data model.[26]

Model Inputs

The technologies available for deployment in the ESO-XEL model, highlighted below, are available throughout the planning horizon considered (2015–2100). Their deployment is driven by the emissions constraints implemented in the model.

- Conventional fossil fuel generation from coal, open-cycle gas turbine (OCGT), and combined-cycle gas turbine (CCGT) power plants. Interconnection with external electricity markets is modeled as infinitely flexible power generation, with limits on generation capacity.
- Firm low-carbon generation from nuclear and biomass plants, and coal and CCGT power plants equipped with post-combustion carbon capture and

storage (CCS). For CCS, we assume a conventional 90% CO_2 capture rate using monoethanolamine (MEA).[27]
- Intermittent low-carbon generation from solar photovoltaics (PV) and wind (onshore and offshore).
- Energy storage provided by batteries (parameterized as lead-acid type) and pumped hydroelectric storage (PHES).
- CDR from BECCS, which also contributes to power generation, and DACS, which is modeled as a power and heat consumer that provides atmospheric CO_2 removal at a cost.[28]

Two archetypes of DACS are currently being developed for commercial purposes; thus, both were considered in the model. The first, DACS-CE, uses a hydroxide sorbent to remove CO_2 from air at a cost of \$94–232/t_{CO_2}; this is being developed by Carbon Engineering.[8] High-grade heat at 900°C (supplied by natural gas) is required to regenerate the capture solution. [29] Because of the high-temperature nature of the DACS-CE process, intermittent operation (say, due to variable energy supply) will lead to repeated heating and cooling of process equipment, which can be a source of efficiency loss or threaten process stability.[30] Thus, inflexible operation—i.e., constant power and heat consumption—is assumed. The second, DACS-CW, is a modular technology that uses an amine-functionalized sorbent and low-grade heat to capture atmospheric CO_2 at a cost of \$600/t_{CO_2}; this is being developed by Climeworks (CW).[31] This archetype can utilize waste heat at relatively low temperatures (100°C); thus, it is assumed to be suitable for flexible operation. Other costs of carbon capture via DACS that have been cited in the literature vary greatly, from 30 to 1,000 \$/t_{CO_2},[32] because they are based on a range of theoretical engineering approaches (i.e., deduced from separation efficiency[33]) or have considered only one aspect of the technology.[34,35] This uncertainty presented a challenge for this study.

The system parameters (demand evolution, initial system design, reserve, and inertia requirements) and carbon prices assumed are detailed in Table S2. Fuel costs assumed in the model are provided in Table S3. Technological parameters (efficiencies, lifetimes, build rates, ramping rates, capital costs, and learning rates) are assumed and given in Table S7. Local and imported biomass sources are considered using a biomass supply curve. This is illustrated in Figure S1 and discussed in detail in Tables S4–S6.

RESULTS

The 2008 Climate Change Act mandates an 80% economy-wide reduction in GHG emissions (relative to 1990 levels) by 2050.[36] This requires a virtual decarbonization of the power sector by 2050.[27] Therefore, for illustrative purposes, we have compared the cost-optimal system transition needed to achieve a decarbonized electricity system by 2050, relative to a transition that meets the UK's purported CDR requirements by 2100. Accordingly, Figure 2 presents the least-cost capacity expansion and electricity dispatch mix for the UK electricity system from 2015 to 2100 in three scenarios: (1) achieving and maintaining a zero-carbon electricity system from 2050 onward, (2) providing 2.8Gt_{CO_2} of CDR by 2100, and (3) providing 9.8 Gt_{CO_2} of CDR by 2100.

We observe that until 2050, the decarbonization pathway for all three scenarios is approximately the same, i.e., carbon intensity falls to zero by mid-century independent of the emissions target imposed. This is largely achieved through extensive expansion of intermittent renewable generation capacity (wind and solar) from 24

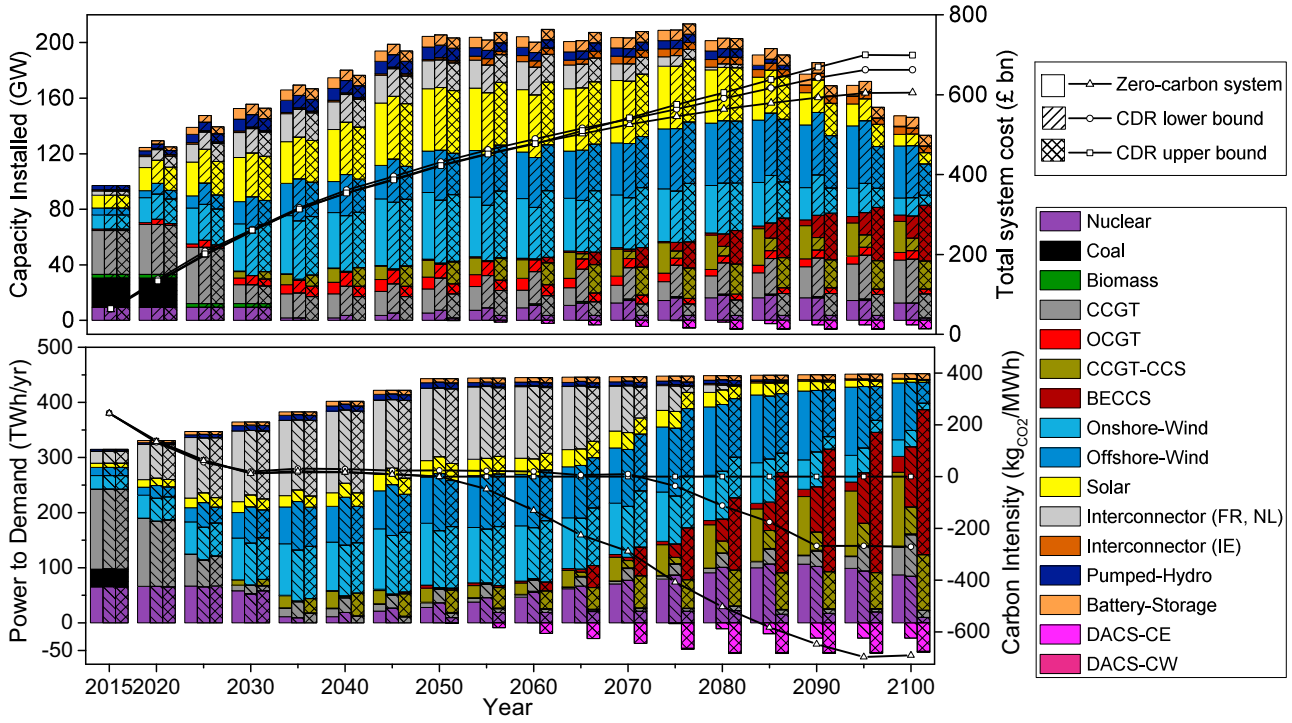

Figure 2. Least-Cost Power Generation Capacity Expansion and Electricity Dispatch Mix from 2015 to 2100 for the UK Electricity System as Forecast by the ESO-XEL Model in Three Scenarios

(Left) Achieving a zero-carbon system by 2050. (Middle) Providing cumulative CDR of 2.8 Gt_{CO_2} by 2100. (Right) Providing cumulative CDR of 9.8 Gt_{CO_2} by 2100.

to 123–126 GW in 2050 (60%–61% of installed capacity). The increasing variability of electricity supply in the system necessitates additional grid flexibility. Consequently, energy storage services and interconnection are expanded simultaneously. PHES deployment reaches its geographically constrained maximum at 9 GW, with 7.2–7.5 GW of battery storage capacity built to supplement. Interconnection experiences similar rates of growth to renewables, with electricity import capability quintupling to 21 GW by mid-century. Concurrently, peaking gas power plants (OCGT) see a 550%–670% increase in installed capacity, reaching 8.5–10 GW, reflecting the need for faster generation output response to increasingly volatile power supply and, inherently, demand.

This proliferation of intermittent renewable energy sources (IRES) coupled with energy storage, however, is insufficient to reach net-zero emissions in a cost-effective manner. While coal is eliminated from the system after 2020, 38–41 GW of gas power plants, both unabated and abated (equipped with CCS), remain in the system to provide crucial ancillary services to maintain grid reliability and/or dispatchable low-carbon power. Existing nuclear capacity (9.6 GW) is only replaced after it reaches operational end-life in 2030 in the "zero-carbon system" and "CDR lower-bound" scenarios; 1.8 GW of new build comes on-line in 2035 and peaks at 16–18 GW in the latter half of the century. In the "CDR upper-bound" scenario, where existing nuclear is not replaced, CCGT-CCS deployment is seen aggressively from 2030 onward, with a total of 15 GW built in 20 years; this highlights the need for dispatchable low-carbon electricity as renewables penetration rises in a carbon-constrained system. As CCS only captures 90% of gas-derived emissions, 0.5–1 GW of BECCS capacity is deployed to compensate for CCGT-CCS residual emissions.

Current global decarbonization efforts largely seek to increase deployment of wind and solar power. The above shows that such a strategy is consistent with the cost-optimal pathway only up to a limit—in the case of the UK, this is until 2050. Beyond this limit, however, the optimal system design to either maintain a zero-carbon system or to meet ambitious CDR burdens differs greatly.

Maintaining a Zero-Carbon System Post-2050

Near- to medium-term decarbonization objectives are satisfied by displacing fossil generation with IRES, as shown from 2020 onward in Figure 2. This is because, despite IRES' low energy density and intermittency—which require additional capacity, energy storage, and grid flexibility to compensate—they provide the cheapest zero-carbon electricity. However, several factors conspire to reduce the relative competitiveness of IRES. Rising demand[37] and the retirement of old fossil and IRES power plants mean there is a significant capacity shortfall that must be replaced quickly. Even the modest learning rates assumed here (see Supplemental Information) result in cheaper firm low-carbon power from CCS plants and exhaustion of storage and available flexibility as interconnection and PHES are maximally deployed. Consequently, for the delivery of zero-carbon electricity, firm low-carbon thermal generation (complemented with some CDR from BECCS to offset residual emissions) proves cheaper than further expansion of IRES. From Figure 2, we observe that IRES capacity falls by more than 50% to 58 GW, while firm low-carbon generation (nuclear, CCGT-CCS, and BECCS) capacity rises from 18 to 40 GW between 2050 and 2100. Total generation capacity, which peaks at 208 GW in 2075, also shrinks to 147 GW in 2100 as a result of the reduced reliance on IRES.

The Challenges of Gigatonne-Scale CDR

The return to a system dominated by thermal power plants is accelerated when CDR targets are imposed because of the increased need for BECCS and DACS. For the lower- and upper-bound CDR requirements, annual CO_2 removal rates rise until the end of the century when it reaches a peak of 159 and 358 Mt_{CO_2}/year, respectively. In 2100, the 16–40 GW of BECCS capacity installed requires 1.2–2.9 EJ/year[38] of bioenergy to provide 57%–63% of annual CDR. Despite the energy-intensive nature of DACS, it provides 46%–61% of total CDR. This highlights the influence of increasing biomass costs as local supplies of waste and virgin biomass are exhausted and import dependence rises (see Supplemental Information). Increased BECCS costs and technology learning conspire to favor DACS deployment over a marginal increase in BECCS capacity. Although DACS-CE has limited learning potential (the majority of the processes involved—absorption, calcination, and compression—use mature technologies) and is unable to operate flexibly, it is the archetype of DACS that is deployed because of its lower capital and operating costs (relative to DACS-CW). Inflexible operation limits DACS-CE's capacity to integrate into an IRES-dominated system, so it is likely that DACS deployment facilitates the resurgence of thermal generation in the system after 2050.

Meeting the required CDR commitments appears not to transgress any biophysical limits. However, the extent of their deployment poses other risks. Total system cost (capital and operating costs throughout the planning horizon) increases by 10%–30%, relative to the "zero-carbon system," for the Paris Agreement-compliant systems. In the worst-case scenario, BECCS is required to generate 280 TWhe/year, equivalent to 55% of annual demand. Because of limited local bioenergy availability, 228 TWhe/year (81%) of BECCS generation relies on imported biomass. Such heavy import dependence will leave the power sector exposed to the volatilities of global supply chains and present energy security concerns. In addition, large volumes of

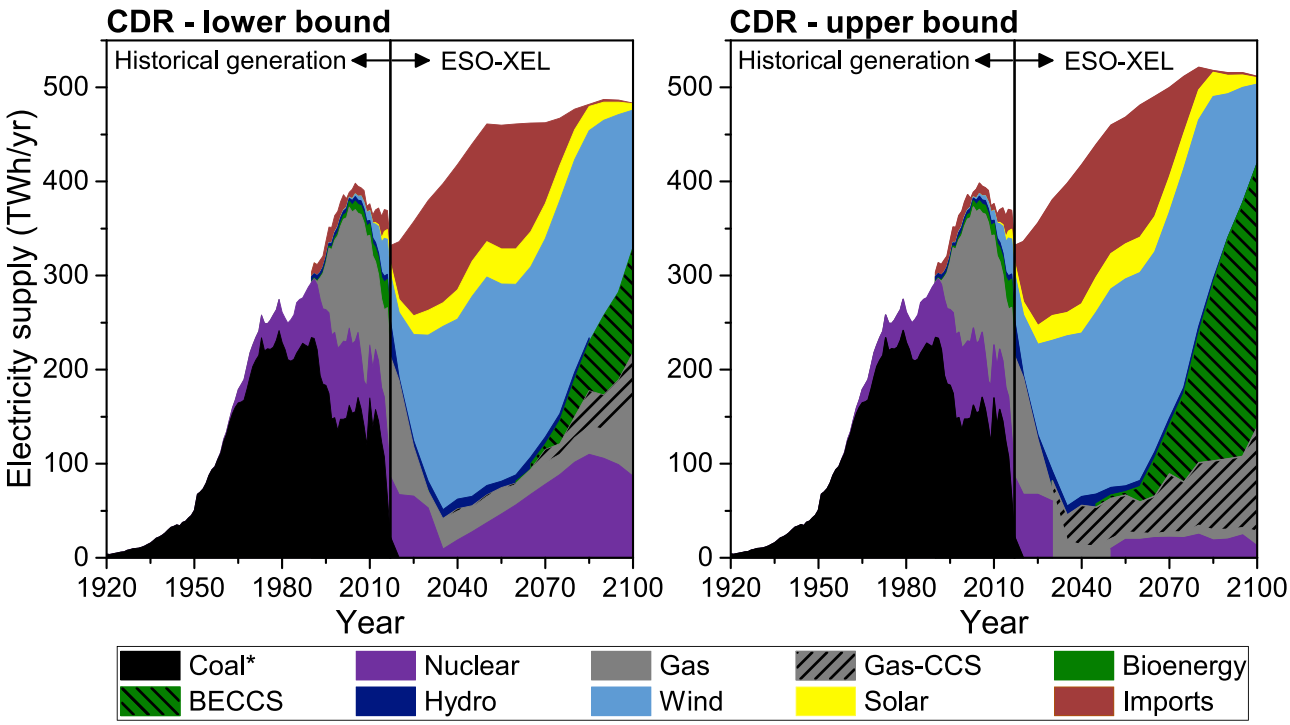

Figure 3. Evolution of the UK Electricity Supply from 2020 to 2100 (as Projected by the ESO-XEL Model) When CDR Requirements Consistent with the Paris Agreement Are Imposed

Historical data from 1920 to 2017 is also shown.

CO_2 need to be transported from 254 large-scale capture units (BECCS, CCGT-CCS, and DACS plants) to suitable storage sites. Therefore, extensive CO_2 transportation networks are necessary as this amount of infrastructure is unlikely to be geographically concentrated. Lastly, DACS deployment adds significant demand to the system. In the upper-bound scenario, DACS consumes 53 TWhe/year in 2100, equivalent to 13% of the annual demand. Figure 2 shows the increase in DACS deployment required to meet more ambitious CDR requirements. From Figure 3, it can be seen that greater electricity supply is needed earlier to satisfy this additional DACS demand.

The Evolution of the Electricity System in a Post-Paris World

The cost of electricity generated from IRES has fallen dramatically in recent years, and this trend is expected to continue in the near future to the extent that subsidy-free IRES will be competitive with conventional generation technologies.[40] This, in addition to the need to decarbonize economies, has resulted in calls for 100% IRES-dependent electricity systems.[41–44] This study has shown that in the long term, such a system is not a cost-effective means to deliver either zero-carbon electricity or the Paris Agreement.

Fossil fuels, particularly coal, have historically dominated the fuel mix for power generation in the UK. Since the 2000s, several policies and legislation have been implemented to spur a transition to less-polluting fuels and renewable sources of energy.[36,45,46] Figure 3 illustrates how the historical transition of electricity supply (from 1920 to 2017) compares with the projections obtained using ESO-XEL (up to 2100). Two future transitions are apparent, with the first being imminent. Spurred by cheap IRES and an urgent need to completely decarbonize, the penetration of

IRES—IRES available capacity relative to total system capacity—increases consistently until mid-century when it reaches a peak of 61%. Increased imports and energy storage compensate for the variability of IRES during this period. Fossil generation—which is from gas only, as coal is eliminated from the system after 2020—is either abated with CCS or greatly reduced. Nuclear capacity is briefly eliminated from the system as existing power plants retire.

The second transition sees the deployment of significant BECCS and DACS capacity to meet rising CDR burden. Retirement of old fossil and IRES capacity, and rising electricity demand (due to electrification, DACS, and economic and population growth)[39] result in a significant capacity shortage. New CCGT-CCS, nuclear, and some unabated gas capacity prove a cheaper generation portfolio to compensate for this shortage, compared to further expansion of IRES and energy storage. This is due to falling CCS costs (due to cost learning from earlier deployment), limited additional storage capacity (PHES and interconnection capacity exhausted), and the higher availabilities of thermal power plants. Therefore, we observe the electricity system return to one dominated by thermal generation, although this is now dependent on bioenergy, nuclear, and gas, as opposed to coal—the historically dominant fuel.

Shifting the Conversation from Low Carbon to Negative Carbon

The ESO-XEL model assumes the perspective of a central planner. However, most countries have enacted some form of liberalization reform in their electricity markets. Investment decisions in power generation are therefore no longer centralized but driven by risk and return prospects. Investment in immature technologies that are unable to meet market-rate returns are incentivized through favorable policies or legislation. In the past two decades, the increased urgency to decarbonize led to a raft of such incentives for renewable energy technologies. Broadly, renewable energy support (RES) is given in the form of quota systems that allocate a portion of generation to IRES (renewables obligation certificates and/or competitive tendering or bidding), incentives that lower the cost of investment (tax credits or exemptions and/or soft or interest-free loans), additional payments for generation (feed-in tariffs [FiTs] and/or contracts-for-difference [CfDs]), carbon pricing to discourage fossil generation, and legislation discouraging CO_2-intensive generation (mandated carbon budgets and/or coal plant bans).[47,48]

This study has shown that despite the cost reductions in IRES—which are a result of some or all of the above incentives—their continued deployment (in the long term) does not provide the least-cost pathway to the Paris Agreement. As subsidy-free IRES becomes commercially viable, support should therefore be redirected to other technologies that are crucial to meeting long-term mitigation objectives, particularly CDR technologies. The services offered by BECCS and DACS in the electricity system are qualitatively different in type and value, and their incentivization should reflect this; that is, while IRES are important parts of a transition to zero-carbon, they are unable to achieve deeper decarbonization objectives that require a negative-carbon electricity system—this is only possible through CDR deployment. Therefore, incentives given to IRES and CDR technologies should reflect their relative importance to deeper decarbonization objectives at the given stage of the energy transition. Table 1 summarizes these services and the instruments that could be used to monetize them. Common to both BECCS and DACS is the ability to provide an atmospheric CO_2 removal service, which is a public good that should be appropriately remunerated. In addition, they can provide CDR to compensate for GHG emissions from CO_2-emitting power plants or other sectors of the economy with

Table 1. Potential Incentives for Services Provided by BECCS and DACS

CDR Techology	Services Provided	Potential Incentives
BECCS	power generation; ancillary services; atmospheric CO_2 removal; CO_2 emissions offset for other; power plants or sectors of the economy	wholesale electricity, market revenue support, e.g., contracts-for-difference; capacity market, ancillary services market; negative emissions credit; auction-able credit to CO_2 emitters
DACS	atmospheric CO_2 removal; CO_2 emissions offset for other; power plants or sectors of the economy	negative emissions credit; auction-able credit to CO_2 emitters

more expensive or difficult mitigation options (such as heat or aviation). Here, BECCS or DACS would allow value to accrue to other assets by allowing them to operate and generate revenue in a carbon-constrained system. The purchase of "negative emissions credits" by the assets so enabled can be used to share some of this value with BECCS and DACS.

Crediting Negative Emissions

The UK has recognized the social cost of carbon[49] and therefore recognized that emitting CO_2 to the atmosphere is imposing a public cost. CO_2 removal is consequently a public good, which could reasonably be expected to be compensated in line with the value of the avoided cost. We introduce the concept of a "negative emissions credit (NEC)" as a payment for the net removal of 1 tonne of CO_2 from the atmosphere. Building on previous work,[50] a cash flow analysis was carried out to understand the effect of remuneration through NECs on the economic viability of first-of-a-kind (FOAK) BECCS and DACS plants. As BECCS also contributes to power generation, it is assumed that it receives revenues from electricity sales at the marginal cost of electricity of the system. Capacity utilization throughout the operational lifetime of the plants is determined from the optimal electricity dispatch profile obtained using the ESO-XEL model.

For a FOAK BECCS plant, an NEC of £52/tCO_2 yields an internal rate of return of 4%, typical for regulated assets. Because of the greater cost of capture and the absence of any other revenue stream, DACS-CE and DACS-CW require NECs of £176/tCO_2 and £342/tCO_2, respectively, to achieve a similar return. High-risk investments, such as those in nascent technologies, often demand higher returns; Figure 4 shows that much higher NEC payments will be needed to achieve higher internal rates of return (IRRs). Nascent technologies typically have IRRs of greater than 10%. Achieving such a return would require NECs of at least £86/tCO_2 and 223–443 £/tCO_2 for BECCS and DACS, respectively.

Revenue Support for BECCS

In addition to providing negative emissions, BECCS can generate electricity to meet demand and provide ancillary services that help to maintain system reliability and operability. Because of its added social utility (climate change mitigation), low-carbon electricity generation is often subsidized through FiT or CfD schemes. Generally, both schemes guarantee stable revenues (at a pre-agreed tariff or "strike price") for generators in a volatile wholesale market. FiTs target small- or medium-scale renewable energy generators, while CfDs target utility-scale generators. In today's paradigm, BECCS would—were it not for other barriers to deployment (lack of CO_2 transport and storage infrastructure and social acceptability of biomass use)—be eligible for such revenue support as it produces negative-carbon electricity that furthers mitigation. Figure 5 illustrates the effect of an NEC and CfD-type incentive on the profitability of a FOAK BECCS plant.

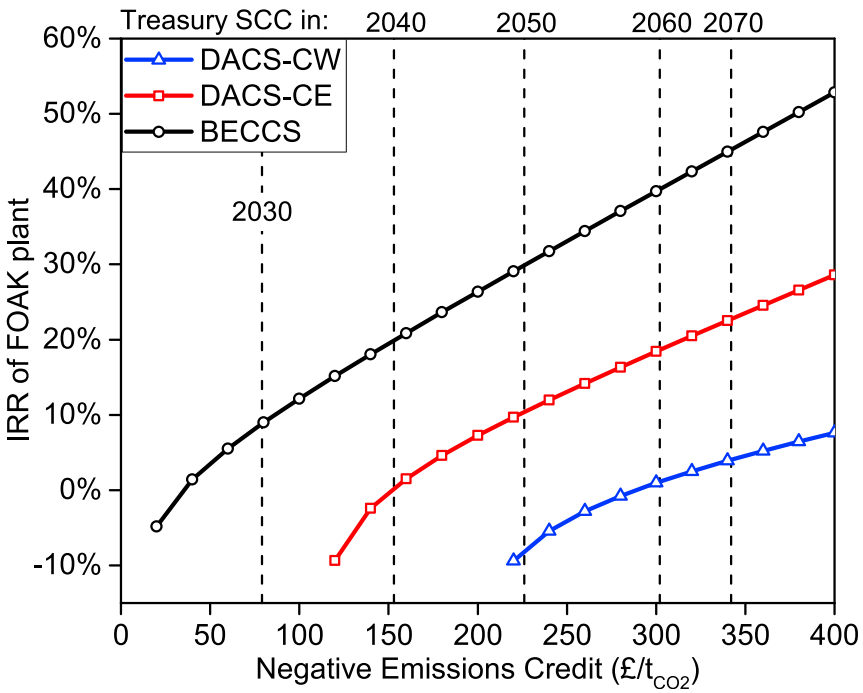

Figure 4. IRR on Investment in FOAK CDR Technologies at Different Negative Emissions Credit Payments

Dashed lines illustrate the social cost of carbon (SCC) in the years labeled, as projected by the UK Treasury.[49]

In the absence of an NEC, BECCS would need a strike price guarantee of 133–188 £/MWh to achieve an IRR of 4%–15%. If BECCS was recognized as a CDR technology solely and not remunerated for power generation, it would need an NEC of 166–234 £/t_{CO2} to generate the same return on investment. Remunerating BECCS for the CDR service alone may well be more politically feasible because that enables BECCS to compete directly in the electricity market, i.e., "subsidy free."

The above highlights that BECCS and DACS are not commercially viable and need significant support before they can be deployed at the scale required. However, it is important to note that the NEC payments required by both technologies are comparable to the carbon prices assumed in IAMs at their time of deployment (2030 for BECCS and 2050 for DACS).[3] In addition, the price guarantee required by BECCS is consistent with what is awarded to IRES through various support schemes.[47]

DISCUSSION

Decarbonization of the UK energy system has so far been driven by increased use of IRES, particularly wind and solar power, which have experienced dramatic cost reductions. Consequently, entirely "wind-, water-, and sunlight-dependent" power generation is being proposed as a long-term strategy that serves climate change mitigation ambitions at least in cost. However, this study has shown that the power system that can deliver the CDR burden consistent with the Paris Agreement, in a cost-effective manner, is dominated by thermal generation, mainly from bioenergy, gas (both with CCS), and nuclear power plants. Policies advocating for increasing penetration of IRES to near-total levels therefore pose the danger of "lock-in" to either an overbuilt power system or one incapable of delivering sufficient climate mitigation.

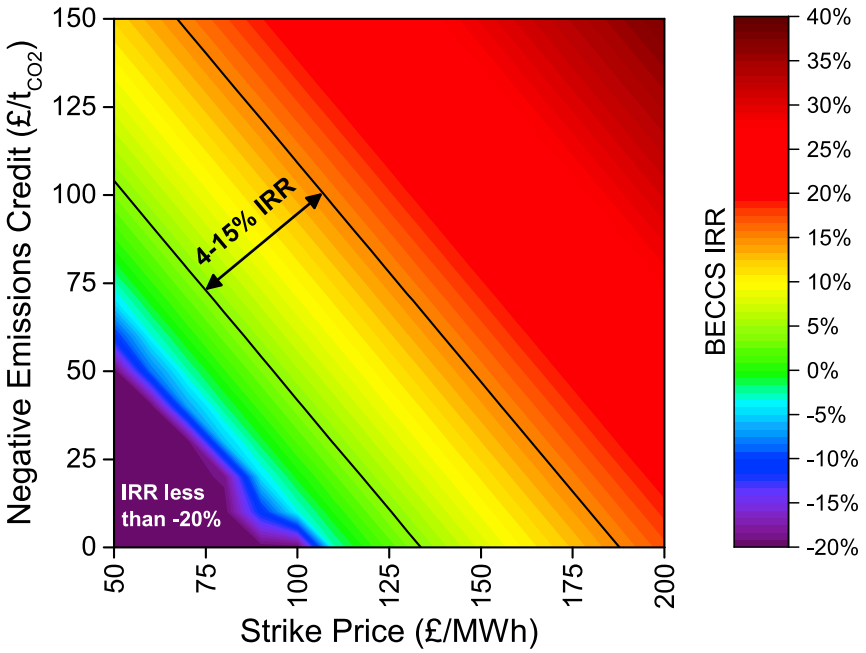

Figure 5. IRR on Investment in a FOAK BECCS Power Plant When It Is Credited for Power Generation at a Strike Price and Credited for CO_2 Removal via a Negative Emissions Credit

For illustrative purposes, scenarios that result in very-negative IRRs (below −20%) are simply shown by the black region.

Cheap IRES also allows for the viability of smaller-scale and isolated power systems and even the participation of traditional energy consumers in power generation. Consequently, decentralization is cited as a major feature of the climate-change-induced energy transition.[51–53] However, a system dominated by utility-scale thermal generation is inherently centralized and requires extensive transmission and distribution networks. Pursuing decentralization efforts in the short term may lead to the disintegration of infrastructure that appears to be critical in the long term.

Although the potential value of BECCS and DACS for deep decarbonization has been exhibited, several barriers—both techno-economic and socio-political—must be overcome for their commercialization to be realized. Most notably, there exist few financial incentives for investment in the technologies. With the exception of voluntary carbon markets, whose traded volumes and price of carbon remain low,[48,54] carbon pricing or emissions trading schemes do not credit CDR from BECCS or DACS. The lack of extensive CO_2 transport and storage infrastructure, or a credit for the sequestration of CO_2, further discourages investment. Significant BECCS and DACS deployment are likely to require international supply chains because of biomass trade and the asymmetric distribution of CO_2 storage sites. How accreditation for CDR should be apportioned to sectors or nations involved in these value chains is yet unresolved. In the case of BECCS, certification schemes to guarantee the sustainability of the domestic, but more so for the internationally traded biomass feedstock, will be challenging because of the complexity of biogenic carbon accounting frameworks.[55–57] Finally, the perception of CDR as a moral hazard, on which focus will redirect support from other components of the mitigation toolbox,[29] generates social acceptability concerns.[58]

Favorable policies and subsidization mechanisms have successfully resulted in IRES achieving grid parity. However, this study has shown that the marginal value of IRES

deployment to deep decarbonization efforts will diminish with time. Instead, new technologies (CCS with both gas and bioenergy) and services (CDR) are needed to achieve further climate mitigation. While significant, the incentives required by these new technologies and services to achieve commercial viability are similar to those given to once-nascent intermittent renewable energy technologies. Policy must therefore recognize their values in an increasingly carbon-constrained world and adequately incentivize them to attract investment and encourage innovation.

SUPPLEMENTAL INFORMATION

Supplemental Information can be found online at https://doi.org/10.1016/j.joule.2019.03.009.

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DECLARATION OF INTERESTS

The authors declare no competing interests.

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